Comments of the Solar Alliance, the California Wind Energy Association, the Large-Scale Solar Association, and the Vote Solar Initiative on the CPUC Energy Division's 33% RPS Report and Model

August 28, 2009

The Solar Alliance, the California Wind Energy Association (CalWEA), the Large-Scale Solar Association (LSA), and the Vote Solar Initiative (Vote Solar) – collectively, the Joint Renewables Parties – appreciate the opportunity to present the following detailed comments on the report *33% Renewables Portfolio Standard: Implementation Analysis Preliminary Report* (Report), issued in June 2009 by the Commission's Energy Division. Although the Joint Renewables Parties have not had the resources to participate actively in the working group that advised the Energy Division during the development of this report, we do believe that the Report is an important step in the development of a workable program that will allow California to reach a 33% renewables portfolio standard (RPS) by 2020. As a result, we have reviewed the Report in detail, and offer the following comments in an effort to assist the Commission to produce, later this year, the most useful Final Report possible.

1) **Introduction and Summary.**

The Energy Division is to be commended for a highly useful and clearly presented report and analysis of the potential costs to California of achieving a 33% Renewables Portfolio Standard (RPS) by 2020. The Joint Renewables Parties believe the Report does an excellent job examining the key drivers of the costs of achieving the RPS goals. However, in addition to the specific issues addressed below, we ask the Commission to consider both the costs *and benefits* of renewable energy development in California. The CPUC must uphold both its obligation to advance the full range of benefits intended by the RPS legislation, as well as its obligation to inform California ratepayers of the true value of their investments – conventional and renewable. Californians need an intelligent cost-benefit analysis in order to make informed decisions on renewable energy, and they are much more likely to agree to the price tag if they understand fully the considerable benefits of what they are buying.

The Report makes an important contribution to the discussion of the very important process and timeline challenges to meeting a 2020 goal for a 33% RPS. The Energy Division's sensitivity analyses look at the important policy options that state regulators should consider in deciding how best to meet these ambitious RPS goals, with the exception of one omission (tradable RECs with no delivery requirement). The 33% RPS spreadsheet model that accompanies the Report is a useful, flexible, and transparent tool for exploring the cost implications of these policy options.

The Report shows that the state faces significant challenges in limiting the cost impacts of a 33% RPS program. However, the Joint Renewables Parties believe that the report makes a number of overly cautious assumptions in calculating the costs to reach a 33% RPS. These assumptions result in a Reference case for a 33% RPS that, we believe, overstates the costs to achieve this goal. More realistic assumptions, as discussed below, show that the 33% RPS goal can be achieved at a more modest cost than presented in the report.

In particular, the Joint Renewables Parties recommend that the Energy Division consider making the following changes in the Report and the associated modeling:

- **RPS Goal.** The 33% Reference case should be modified to use a less conservative estimate of demand in 2020 and a more accurate estimate of the GWh needed to meet a 33% RPS goal. The projection of demand in 2020 should not downplay the state's other key initiatives to meet its 2020 targets for greenhouse gas (GHG) emissions, including the California Solar Initiative (CSI) and the development of new combined heat and power (CHP) facilities.

- **CSI.** Because the CSI is an approved, established program that is meeting its targets, the 33% Reference case should assume that the CSI meets its goals for 3,000 MW of behind-the-meter PV by 2020. This would be consistent with both the assumptions used in the Renewable Energy Transmission Initiative (RETI) and the Commission's comments on the most recent demand forecast from the staff at the California Energy Commission (CEC).

- **CHP.** Given the commitment that the Commission and the California Air Resources Board (CARB) have made to expanding the state's combined heat and power resources, the demand forecast in the 33% Reference case should include a reasonable estimate of new, behind-the-meter CHP in 2020.

- **Existing RPS Generation.** The amount of new RPS generation needed by 2020 should be calculated using RPS generation through 2008, as reflected in recent IOU and ESP 2009 RPS compliance filings.

- **Solar Costs.** The costs of large-scale solar photovoltaic (PV) and solar thermal-to-electric projects used in the 33% Reference and other cases should be reduced to bring them in line with the most recent studies and data on the costs of solar technologies.

- **Combined Wind & Solar Use of Transmission Lines.** The Energy Division should assume that the combination of wind and solar projects can optimize the capacity and maximize the use of new transmission lines.

- **Low Wind Cost Sensitivity.** The Final Report should add a sensitivity case using low wind costs from the Department of Energy's *20% Wind by 2030* study.

- **RPS as a Gas Price Hedge.** The Report's analysis of whether renewables function as a hedge against high gas prices is flawed. It is not correct simply to look at the costs of a 33% RPS under a high gas cost scenario compared to an All Gas scenario at the same high gas prices. Renewables reduce the demand for natural gas, and thus lower gas market prices. A 33% RPS will lower the probability that the high gas cost scenario will occur, compared to the All Gas case. Viewed properly, a

33% RPS provides very significant benefits as a hedge against high natural gas prices.

- **Below MPR Contracts.** The 33% Reference case should not ignore the fact that many existing RPS contracts are priced below the MPR. As a result, the 33% Reference case should include savings from below-MPR contracts as a base case assumption.

- **Tradable REC Sensitivity.** The use of tradable RECs from out-of-state resources is a controversial issue. Nonetheless, the Final Report should add a sensitivity case for a limited amount (20%) of tradable RECs with no in-state delivery requirement, so that policymakers can understand the cost consequences of such a policy.

- **The High DG Case.** The High DG Case makes a number of questionable assumptions in determining both the mix and the cost of the DG generation in the scenario. The High DG case should be revised to eliminate the distinction between urban and rural/remote DG, and to use the DG costs assumed for urban DG (including avoided T&D charges) for all 15,000 MW of DG in the High DG case.

- **Avoided T&D Costs.** The Joint Renewables Parties strongly support the 33% RPS model's application to DG of avoided T&D costs from the E3 energy efficiency model. This is consistent with the CPUC's just-issued order on assessing the cost-effectiveness of DG.

- **Integration Costs.** The Energy Division should ensure that the CAISO's 33% RPS integration studies include realistic scenarios for the future diversity of the state's renewable resources, including both wind and solar resources.

The Joint Renewables Parties have run a revised version of the 33% Reference case that includes a lower RPS goal, reduced solar costs, and savings from below MPR contracts, as recommended in these comments. In this revised 33% Reference case, the cost impact of a 33% RPS in 2020 is reduced from 7.1% to 2.9% higher than the 20% RPS scenario.

2) **The RPS Goal in the 33% Reference Case Should Not Be So Conservative, and Should Consider Other Important State Initiatives to Reduce GHG Emissions.**

The 33% Reference case should be modified to use a less conservative estimate of demand in 2020 and a more accurate estimate of existing (2008) renewable generation in California. These changes will result in a more accurate and realistic projection of the GWh of energy needed to meet a 33% RPS goal in a base case scenario.

Demand Forecast for 2020. The demand forecast for 2020 used in the 33% Reference case does not venture beyond the California Energy Commission's (CEC) *2007 Integrated Energy Policy Report (2007 IEPR)* demand forecast, even though developments since 2007 argue strongly for at least modest adjustments to that now-dated demand forecast.

First, the CPUC's most recent long-term procurement planning (LTPP) decision (D. 07-12-052) adopted the use of 100% of 2020 goals for energy efficiency savings. The *2007 IEPR* demand forecast included only 80% of these goals on the grounds that 20% were "uncommitted." The Commission committed to the final 20% of these savings in D. 07-12-052. The use of 100% of these savings also is reasonable given the top priority accorded to energy efficiency in the state's loading order and given that the Commission is now investigating even more ambitious "Big Bold" energy efficiency goals.[1] This adjustment to include the 20% of formerly uncommitted savings would reduce the 2020 demand forecast by 4,000 GWh. This adjustment appears to be modest, given that the current economic difficulties have reduced electric demand substantially, and the CEC staff's draft demand forecast for the *2009 IEPR*, released in June 2009, shows 9% (30,000 GWh) lower demand in 2018 than in the *2007 IEPR* demand forecast.[2] If the CEC adopts the staff's draft demand forecast for the *2009 IEPR*, then the Report's Low Load sensitivity case may become the new base case.

Second, the *2007 IEPR* demand forecast includes only 847 MW of demand-side PV development under the CSI by 2020. This is based on the 2004 – 2006 pace of PV installations under the CSI's predecessor programs.[3] The pace of PV installations has accelerated since 2007 under the CSI, and the program remains on target to reach its 3,000 MW goal by 2016, according to the most recent CSI annual report.[4] Furthermore, it makes little sense for the 33% Reference case to include 3,325 MW of wholesale solar PV, but just a fraction of the CSI goal, when the CSI offers financial incentives to behind-the-meter PV development that are unavailable to wholesale PV. We note that, in contrast to the Report, the RETI Phase 1B Report assumed that the CSI will meet its full goals by 2016, then continue to install additional solar DG through 2020, resulting in 4,200 MW (7,358 GWh at a 20% capacity factor) of end-use demand reductions in 2020. Given that the CSI is an approved, ongoing program that is meeting its goals and that has been included in the CARB's 2008 Scoping Plan for meeting the state's 2020 GHG targets, the Joint Renewables Parties believe that the 33% Reference case should assume, at a minimum, that the CSI meets its goals for 3,000 MW (5,256 GWh at a 20% capacity factor) of behind-the-meter PV by 2020. This is broadly consistent with the Commission's recent recommendations to the CEC concerning the *2009 IEPR* demand forecast.[5] This results in an incremental demand reduction in 2020 of 3,772 GWh compared to the current 33% Reference case.

Third, the CARB Scoping Plan and the CPUC / CEC Final Decision on GHG Regulatory Strategies (D. 08-10-037) both signaled that incremental development of

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[1] *See* D. 07-10-032.

[2] *See* "California Energy Demand 2010 - 2020: Staff Draft Forecast," (June 2009, CEC-200-2009-012-SD), at 2 and Table ES-1, available at http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SD.PDF.

[3] *See* "California Energy Demand 2008 – 2018: Staff Revised Forecast," (November 2007, CEC-200-2007-015-SF2) at 31, available at http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF.

[4] "California Solar Initiative: Annual Program Assessment" (June 2009, CPUC), at 17-18. This document is available at http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/103173.PDF .

[5] "Comments of the California Public Utilities Commission's Energy Division on the *California Energy Demand 2010 - 2020: Staff Draft Forecast*," (prepared for the June 26, 2009 CEC workshop on the *2009 IEPR*), at 8-10. Available at http://www.energy.ca.gov/2009_energypolicy/documents/2009-06-26_workshop/comments/Julie_Fitch_California_Public_Utilities_Commission_Energy_Division_TN-52379.PDF .

California's CHP resources would be an important GHG mitigation measure.[6] The *2007 IEPR* demand forecast includes no incremental CHP. It may be premature to use the full 4,000 MW of incremental CHP called for in the CARB Scoping Plan, because the state's plans to encourage CHP development have yet to be formalized. However, it is equally a mistake to ignore this goal and these resources completely. The CEC's most recent CHP market assessment, presented in July 2009, shows a "base case" (i.e. without any new policy support) increase in small CHP serving on-site loads of about 2,000 MW by 2020.[7] Assuming that this CHP operates with a capacity factor of 75% yields a 2020 demand reduction of 13,140 GWh. The CPUC should assume at least this additional amount of on-site CHP by 2020.

Existing Renewable Generation. Page 16 of the Report's "Inputs & Assumptions" documentation notes that the RETI Phase 1B report uses a figure for existing in-state renewable generation in 2007 that is almost 13,000 GWh, or 48%, higher than the 27,063 GWh assumed in the Report. This is a very substantial difference for an historical number that should be verifiable. The Report's documentation does not justify why the lower figure that it uses for existing RPS generation is reasonable, but the Final Report should do so. The 33% RPS Report uses specified renewable generation for 2007 reported in the CEC's annual *Net System Power* report, and does not include any unspecified renewable generation imported from out-of-state. The RETI report appears to use "energy from renewable projects planned and under construction as of 2008," which may overestimate existing RPS generation. As a compromise, the CPUC should consider adding the 4,716 GWh in 2007 of unspecified renewable imports calculated by the CEC to the 27,063 GWh of specified renewable generation serving California. At a minimum, the Energy Division should add the documented increase in annual RPS generation from 2007 to 2008 that the IOUs and ESPs recently have filed with the CPUC in their 2009 RPS compliance reports. The increase in renewable generation in 2008 over 2007 amounts to 1,049 GWh for the three IOUs alone.[8]

Based on the above discussion, the Joint Renewables Parties recommend that the Energy Division's Final Report should make the adjustments listed in **Table 1** to the 2020 demand forecast used in the 33% Reference case, to the 33% RPS goal in 2020, and to the quantity of new RPS generation that must be added by 2020 to meet that goal. Note that these adjustments to 2020 retail sales are substantially less than those assumed in the Report's Low Load Sensitivity; we do not recommend any further changes to that sensitivity.

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[6] D. 08-10-037, at 16-17 and 102-105.

[7] See "CHP Market Assessment," ICF presentation to the CEC's July 23, 2009 workshop, at 23 (On-site CHP plus Avoided AC [Air Condiitoning]) and 33. This study is available at http://www.energy.ca.gov/2009_energypolicy/documents/2009-07-23_workshop/2009-07-15_ICF_CHP_Market_Assessment.pdf.

[8] *See* PG&E, SCE, and SDG&E 2009 RPS compliance reports filed August 3, 2009 in R. 08-08-009.

Table 1: *Recommended Changes to 2020 Retail Sales and RPS Goal*

	Changes to 33% Reference Case *(GWh)*	*Source:*
2020 Final Retail Sales	308,220	Report, Inputs & Assumptions, at Table 12.
DSM Committed by D. 07-012-052	(4,000)	Report, at Table 7.
CSI above *2007 IEPR*	(3,772)	Assume 3,000 MW in 2020 at a 20% capacity factor.
New on-site CHP	(13,140)	CEC CHP Assessment for *2009 IEPR*, 75% capacity factor.
Revised 2020 Retail Sales	287,308	Sum of the above.
Revised 2020 RPS Goal	95,769	33% of revised 2020 retail sales.
2007 RPS Generation	(27,063)	Report, Inputs & Assumptions, at Table 12. From CEC's 2007 *Net System Power Report.*
Incremental 2008 RPS Generation	(1,049)	2009 RPS Compliance reports for the three IOUs.
New RPS Generation Needed by 2020.	67,657	

3) **The Report's Assumed Costs for Solar PV and Solar Thermal Are Too High.**

The Report's assumptions for the costs of large-scale solar projects are unreasonably high and are out of step with recent reports.

First, the Report assumes a cost of $7.10 per watt (AC) for the capital costs of large-scale solar PV generation, not including cost penalties of 8% to 21% for roof mountings. This assumed cost is much too high. The consultant KEMA recently submitted a report as part of the CEC's *2009 IEPR* proceeding that documents a 2009 cost of $4.55 per watt (AC) for large-scale solar PV projects.[9] The cost target for the 500 MW of new PV generation in Southern California Edison's recently-approved Solar PV Program, which focuses on rooftop projects, is $3.50 to $3.85 per watt (DC) for projects of 1 to 2 MW to be installed over the next five years.[10] $3.50 to $3.85 per watt (DC) is equivalent to $4.20 to $4.62 per watt (AC). SCE completed its initial installation for the SPVP program (a 2.25 MW rooftop project in Fontana) in December 2008 at a cost of $4.30 per watt (DC).[11] PG&E's pending application for approval of its similar 500 MW PV program cites a cost target very similar to SCE's.[12] The $4.55 per watt (AC) cost for solar PV should be used as the base case, reference value; the PV

[9] "Renewable Energy Cost of Generation Update," (August 2009, CEC-500-2009-084), at 96-101 (the KEMA Report). KEMA's recommended solar PV costs of $4,550 per kW are included in the CEC Staff Draft Report "Comparative Costs of California Central Station Generation" (August 2009, CEC-200-2009-017-SD), at Table 14 (CEC 2009 Cost of Generation Report). These documents are available at http://www.energy.ca.gov/2009_energypolicy/documents/index.html#082509 .

[10] *See* D. 09-06-049, at 7.

[11] A. 08-03-015, Exhibit SCE-2, at 15.

[12] A. 09-02-019, Exhibit PG&E-3 (July 15, 2009), at 1-2.

costs used in the Report's "Low Solar Costs" sensitivity case ($3.70 per watt AC) are reasonable.

Second, the Report uses a cost of $4.90 per watt for the capital cost of large-scale solar thermal-to-electric generation. This assumed cost also should be revisited in light of the KEMA report. The KEMA report documents a $3.67 per watt cost for solar parabolic trough technologies, which are well-established and the most conservative of the solar thermal technologies.[13] While parabolic trough is only one type of solar thermal technology, its cost improvements in recent years are, at a minimum, a conservative indicator of the costs for the broader category of solar thermal-to-electric technologies.

4) **Assume that Wind & Solar Combine to Maximize Use of Transmission Lines.**

The assumed costs for new transmission used in the Report are derived from a transmission costing model that E3 developed for its GHG calculator, rather than from the transmission costs in the RETI reports. In the RETI process, CalWEA has expressed serious concerns that the RETI transmission costs are overstated. E3's transmission costing model correctly excludes existing Transmission Access Charge (TAC) costs from the incremental transmission costs for new renewables, and the model does assume that new transmission lines can accommodate more than their rated capacity of renewables, provided there is diversity among the renewable generation (i.e. wind and solar). The Joint Renewables Parties recommend that E3 consider using the Net Qualifying Capacity levels for solar and wind to estimate the portion of nameplate generation capacity that would require transmission capacity. If that is not possible, a proxy that could be used for high-level modeling is 80% of solar nameplate / 25% of wind nameplate for on-peak capacity and 80% of wind / 25% of solar nameplate for off-peak. This would be similar to the approach taken by RETI in Phase 2A (but without the CREZ-specific detail).

Generally, the Commission also should be cognizant that zonal cost data derived from this Report or from the RETI process are at a very high level, are subject to significant uncertainty, and are not suitable for the evaluation of specific RPS projects.

5) **The Final Report Should Add a Sensitivity Case for Low Wind Costs.**

The Final Report should include a sensitivity scenario for Low Wind Costs, similar to the Low Solar Costs sensitivity. This sensitivity should be based on the Department of Energy's (DOE) 2008 report on reaching 20% wind generation in the U.S. by 2030.[14] DOE believes that wind costs can be reduced by 10% by 2030 through the use of taller towers, larger and lighter rotors, and continuing progress through the design and manufacturing learning curve. Further, wind capacity factors can be improved by 15% in all wind classes by 2030. Thus, a reasonable Low Wind cost sensitivity for 2020 would be to reduce wind capital costs by 5% and raise wind capacity factors by 7.5%, thus reaching one-half of DOE's goals by 2020. Although these changes are small in percentage terms, they are significant given the substantial amounts of new wind generation in most of the 33% RPS cases.

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[13] KEMA Report, at 84-96; CEC 2009 Cost of Generation Report, at Table 14.

[14] This DOE report is available at: http://www.20percentwind.org/. See esp. page 40, Table A-1, and Appendix B.

6) **The Report Is Wrong In Concluding That a 33% RPS Is a Poor Gas Price Hedge.**

The Report concludes that a 33% RPS will not result in a significant hedge against high natural gas prices. This conclusion is based on sensitivity results for a high gas cost case, in which statewide electricity costs in the 33% Reference case are still higher than the All Gas scenario, *but assume the same high gas price*.[15] This argument does not recognize correctly how renewables function as a hedge against high gas prices. Renewables reduce the demand for natural gas, and thus *decrease* the market price compared to a world with fewer renewables. As a result, a 33% RPS will lower the probability that the high gas cost scenario will occur, compared to the All Gas case. This is how renewables hedge against high gas prices. Researchers at Lawrence Berkeley National Laboratory (LBNL) have calculated that each MWh of renewable generation generates $7.50 to $20 in consumer savings from lower natural gas market prices.[16] Assuming an incremental 68,000 GWh of renewable generation in the state in 2020, these savings are $0.5 to $1.4 billion per year, which is a significant consumer benefit by any measure.

7) **The Costs for the 33% Reference Case Should Include Below MPR Contracts.**

The 33% RPS model assumes that any renewable resource whose costs are less than the costs of a combined-cycle plant (i.e. below the market price referent [MPR]) will be priced at 100% of the costs of a combined-cycle. This ignores the fact that competition in past RPS solicitations has resulted in many RPS contracts priced below the MPR, contracts which now produce consumer savings relative to gas-fired capacity. The 33% Reference case should not ignore this experience, and should include savings from below-MPR contracts as a base case assumption. We are not aware of any policy or legislative proposal that would place a floor of the MPR on new RPS contracts, and it is a disservice to consumers to assume that no below-MPR contracts will be obtained in the future. The Joint Renewables Parties appreciate that the 33% RPS model has a flag that can be changed to model the inclusion of below-MPR contracts; our point is that the 33% Reference case should include below-MPR contracts as a base case assumption rather than as a sensitivity.

8) **The Final Report Should Add a Sensitivity Case for Tradable RECs with No Delivery Requirement.**

The 33% RPS model assumes the current delivery requirement, as defined in statute, for out-of-state renewables, thus precluding the use of tradable RECs without a delivery requirement.[17] The issue of the delivery requirement for tradable RECs is controversial; nonetheless, for the purpose of a full exploration of the policy options for a 33% RPS, it would be useful to adapt the model to consider a case in which a limited percentage of RPS generation (say, 20%, or tracking whatever percentage is included in the pending 33% RPS

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15 Report, at 26 and Figure 3.

16 R. Wiser, M. Bolinger, M. St. Clair, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (January 2005, LBNL-56756), at ix., available at http://eetd.lbl.gov/EA/EMP.

17 Report, at 2 and 20.

legislation, should it be adopted this fall) could be obtained from out-of-state RECs without a delivery requirement. This would allow an assessment, as a sensitivity case, of the savings in transmission costs that might be realized under such a policy. Resource costs also might be lower as a result of better resources and lower development costs out-of-state.

9) The High DG Case Makes Questionable Assumptions In Determining the Mix and Costs of DG in this Scenario; the Case Should Treat All DG Consistently.

The Report's High DG case assumes over 15,000 MW of new DG is installed by 2020. This is clearly a very substantial amount of new DG, and we do not question the amount of DG used in this case. However, we are concerned with the mix and cost structure assumed for the DG resources used in this scenario and with a transmission cost penalty applied to almost 60% of this DG. The High DG case assumes just 6,000 MW of DG installations in urban areas, plus 9,000 MW of "remote DG" located near apparently non-urban substations to which is applied a substantial transmission cost penalty ($52 per MWh, based on the cost of a step-up transformer for a 20 MW PV project).

We question the *ad hoc* assumptions used to limit the DG capacity in urban areas, including the limitation to rooftops within 3 miles of substations, the limitation to 30% of substation capacity, and the assumption that only one-third of candidate roofs will agree to be used for a DG installation.[18] Roof tops are not the only urban sites suitable for solar PV; large open spaces such as parking lots also can be used.[19] We do not agree that it makes sense to use as a screening criterion that a project must be within 3 miles of a substation to allow an "easy" interconnection to a distribution circuit. Rule 21 currently provides for a simplified interconnection process for projects that do not exceed 15% of the capacity of a distribution feeder; there is no limitation in Rule 21 based on distance from a substation. In addition, the 15% limit in Rule 21 simply distinguishes between projects that qualify for the simplest interconnection process and those that require more study and perhaps an interconnection with more elaborate protective equipment. The 15% limit does not in any way represent a physical or economic limit on the amount of DG that can be installed on a distribution circuit, nor are we aware that the limitation to 30% of substation capacity reflects a real physical or economic constraint. Clearly, there are likely to be limits on the amount of solar DG that can be installed on distribution circuits (and the SCE and PG&E PV programs will provide valuable experience in this regard), but the screening limits that E3 proposes do not appear to be supported by significant evidence or documentation. Similarly, the assumption that only one-third of potential customers will allow installations is explained as a "simple rule of thumb," without further support.[20]

Also of concern is the treatment given to "remote" and "rural" DG not located in urban areas. First, it is unclear what the distinction is between "remote" and "rural" DG. Obviously, siting DG in rural areas should be easier given the greater availability of open land. Yet E3 applies stricter limits to the amount of DG capacity that can be interconnected at rural

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[18] Report, Appendix B at 71-72 and Tables 16-17.

[19] For example, PG&E's PV program plans to target large open spaces near substations. A. 09-02-019, Exh. PG&E-1, at 2-3 to 2-4.

[20] Report, Appendix B at 71.

substations than on urban circuits, without support except for the vague assertion that "a rural substation will vary more, so its ability to accept interconnections will be reduced."[21] This is a slender thread on which to base limiting DG installed at rural substations to no more than 10% of substation capacity, when a 30% limit is used in urban settings. Again, there is nothing in Rule 21 that would justify such a limitation or that distinguishes between urban and rural interconnections. Equally unsupported is the $52 per MWh cost penalty that E3 assigns to "remote" DG on the grounds that 20 MW PV projects interconnected to remote substations will require step-up transformers.[22] We question why this penalty is applied to remote DG when E3 clearly assumes that urban DG can be sited not only to avoid such a penalty, but to avoid transmission and distribution costs, an assumption that we strongly support. For example, if remote 20 MW PV installations would require such costly transformers, developers probably would install multiple smaller projects to avoid such costs, as E3 assumes they will do in urban areas.

In sum, the Report does not adequately justify the assumption in the High DG case that almost 60% of DG capacity will be installed in remote areas and will carry a significant transmission cost penalty compared to urban DG. The High DG case should be revised to eliminate the distinction between urban and rural or remote DG, and to use the DG costs assumed for urban DG (including avoided T&D charges) for all 15,000 MW of DG in the High DG case.

10) **The Report's Assumption That a High Penetration of DG Will Avoid T&D Costs Is Appropriate and Important.**

The Joint Renewables Parties strongly support the 33% RPS model's application to DG of avoided T&D costs from the E3 energy efficiency model. This is consistent with the order that the Commission just issued on assessing the cost-effectiveness of DG, which adopts Itron's approach of using the E3 energy efficiency model to assess the T&D costs avoided by DG.[23]

11) **The CAISO's Examination of Integration Costs Should Use Realistic Scenarios for the Diversity of the State's Renewable Resources.**

The 33% RPS model uses "placeholder" values for renewables integration costs, pending the CAISO's completion of its 33% RPS integration studies. Although it is thus perhaps premature to comment on integration issues, on a preliminary basis we would make the general comment that all of the 33% RPS scenarios in the Report include significant amounts of both wind and solar generation. Past work on renewables integration, in particular the CEC's Intermittency Analysis Project and NERC's April 2009 special report on renewables integration, have emphasized the complementary nature of wind and solar generation and the

[21] Report, "Inputs & Assumptions," at 5, footnote 14.

[22] Report, "Inputs & Assumptions," at 5. Elsewhere in the Report's documentation, E3 cites a cost penalty of $68 per kW-year, which would be $33 per MWh at a 24% capacity factor. *See* Report, Appendix B at Table 16; also "Resource Ranking & Selection," at 7. We also note that $68 per kW-year is far above the marginal cost of substation capacity, which SDG&E calculated in its last general rate case to be $18.48 per kW-year (A. 07-01-047, Exh. SDG&E-4, at Attachment JSP-4-2).

[23] D. 09-08-026, at 34-36.

fact that the presence of both resources may reduce integration costs.[24] In contrast, the CAISO's past RPS integration studies have examined high levels of wind generation only, without significant solar capacity.[25] In evaluating the CAISO's work, the Energy Division should ensure that it includes realistic scenarios for the future diversity of the state's renewable resources.

12) **Recommended Reference Case**

The Joint Renewables Parties recommend that the Energy Division should revise the 33% Reference case as recommended above, including:

a) A lower 33% RPS goal,
b) Reduced solar PV and solar thermal costs, and
c) Savings from below MPR contracts.

These revised assumptions reduce the 2020 cost impact of a 33% RPS from 7.1% to 2.9%, compared to the 20% RPS case. The remaining changes recommended in these comments will impact other scenarios or sensitivity cases.

13) **Conclusion**

The Joint Renewables Parties appreciate the Energy Division's consideration of these comments, and look forward to the Final Report on a 33% RPS. We also urge the Commission to extend the excellent work in this report from one dimension – the costs of a 33% RPS – to two dimensions – the costs and the benefits of this important policy initiative. For the Report to be complete as a policy assessment, it should evaluate not only the relative costs, but also the comparative benefits of each scenario – in other words, what each scenario actually will do, or fail to do, for California. We are hopeful that the Final Report will undertake the additional work needed to present a full, two-dimensional evaluation of the RPS.

Respectfully submitted,

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[24] "Accommodating High Levels of Variable Generation," (April 2009, NERC Special Report), at 24. This report is available on the NERC website at http://www.nerc.com/files/IVGTF_Report_041609.pdf .

[25] "Integration of Renewable Resources" (November 2007, CAISO), at 2-3, 24, and 68, available at http://www.caiso.com/1ca5/1ca5a7a026270.pdf .